Advanced Inverter Status, CA & HI

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NREL Integrating PV in Distribution Grids

Golden CO, October 2015

Presentation Overview

- **Acknowledgements**
- **Attached to Integrated, the path forward**
- **Advanced Inverter Functions**
  - Improved grid stability
  - Voltage regulation
- **California Rule 21 Update**
- **Hawai’i Experience**
- **Summary and Next Steps**

Acknowledgments

- This presentation gives an overview of the status of advanced inverter functionality and the ongoing regulatory and policy developments underway in CA Rule 21, Hawaii Rule 14H, UL 1741, and IEEE 1547.
- The summaries provided herein are based on the work done to date by the California Smart Inverter Working Group (SIWG), Sandia, Hawaiian Electric Inc. and the UL 1741 / IEEE 1547 Working Groups for ride through, anti-islanding, and active and reactive power control.
- This work is part of an evolving consensus based activity involving utilities and inverter industry members of the Smart Inverter Working Group and those participating in the UL 1741 / IEEE 1547 revision process. – PLEASE PARTICIPATE!

From Attached to Integrated

Distributed Energy Resource (DER) Providers

- *New technology*
- *High costs, low penetration*
- *Evolving business model*

"Early Days"

- *Limited technical and business impact*
- *Ignore, deny impact*
- *Business as usual*

- *Proven technology, lower costs*
- *Higher penetration driven by innovative business models*

"Attached"

TODAY

- *Business challenges (lost revenue, cost to stabilize)*
- *Technical challenges – grid stability*
- *Fight, reluctant acceptance*

- *High penetration*
- *Distributed DER control*
- *Provide stability services for Utility*
- *Provide visualization at grid edge*

"Integrated"

- *Better visibility and control of DER*
- *Integrated planning*
- *Improved utility business models and valuation.*

"Islandable microgrids?" Transactive marketplace?

Utilities

The Early Days (2000 - 2003)

- **Grid tied PV systems were rare**
- **General philosophy was:**
  - Produce unity power factor
  - Get out of the way quickly if anything bad happened
  - Tight trip limits
  - No requirements for ride through
- **Relevant Standards**
  - UL 1741, IEEE 1547, 1547.1

Today (2014 - 2016)

- **CA rule 21 approves smart inverter functionality. Phase 1 autonomous behaviors (Dec 2015)**
  - Voltage and frequency ride through
  - Active and reactive power control
  - Return to service behaviors / ramp rate control
- **Hawaiian Electric Inc. implements mandatory ride through requirements (Jan 2015)**
- **CA rule 21 Phase 2 in development.**
  - IEC 61850 data model, IEEE 2030.5 / SEP 2.0 Protocol
  - Updates to interconnection handbooks under development
- **Relevant Standards**
  - UL 1741, UL 1741 Supplement A, IEEE 1547, 1547.a,1547.1
  - IEC 61850, IEEE 2030.5
  - UL 1998 (firmware certification)

Advanced Inverter Functions

What are they and why do we need them anyway ?

New Regulatory Concepts (in the US)

- **Voltage and frequency ride through**
  - ***Must not trip*** requirements during abnormal excursions
- **Real and reactive power control**
  - Provides frequency stability and voltage regulation
- **Operating regions with differing behaviors**
  - Multiple areas are bounded by pair points of Voltage/time or frequency/time
- **Cease to energize (momentary cessation)**
  - A mode where the DER must cease to energize the area EPS but ***must not trip***.
- **Return to service**
  - The criteria and behaviors required as the DER re-energizes the area EPS following an excursion

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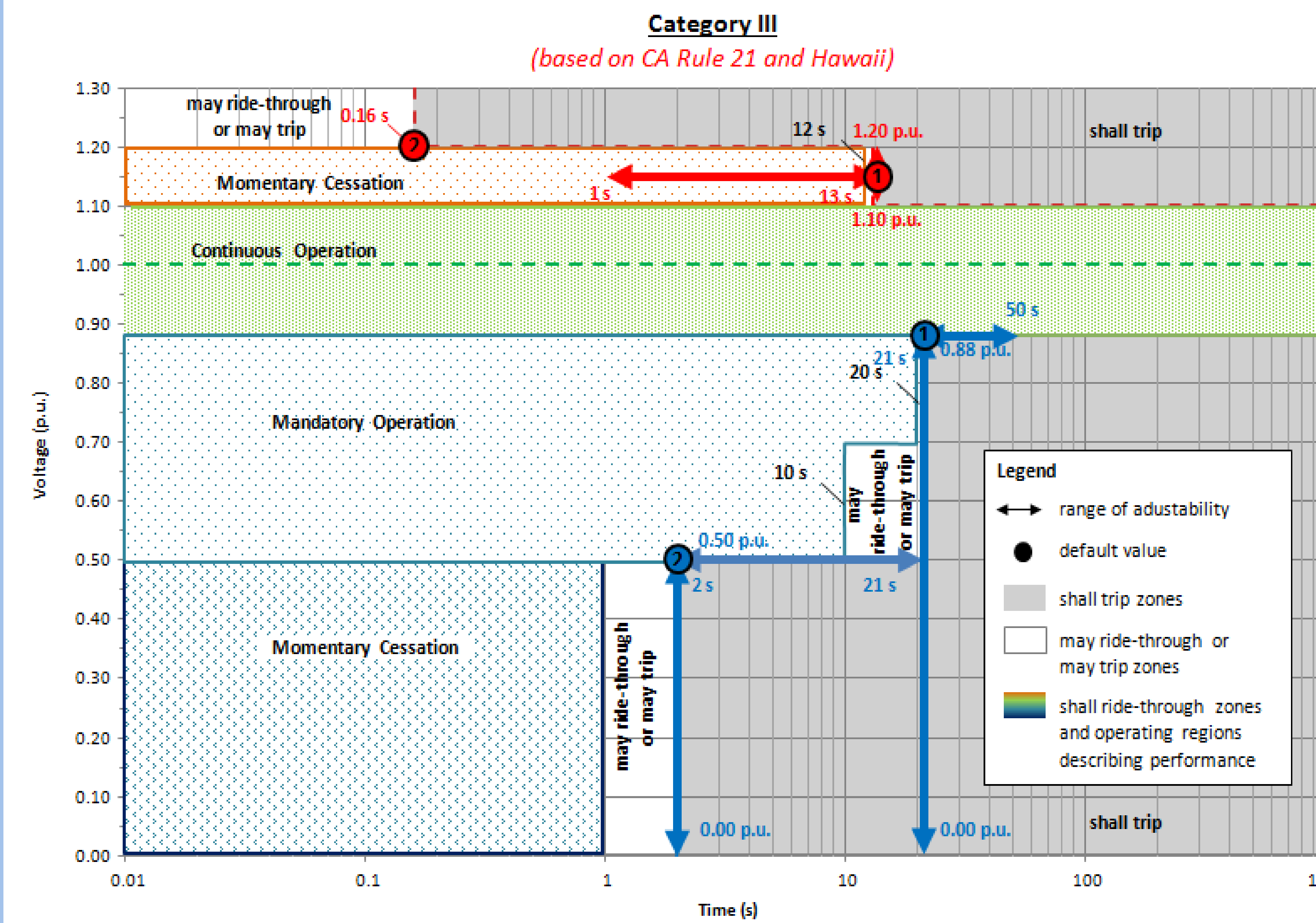
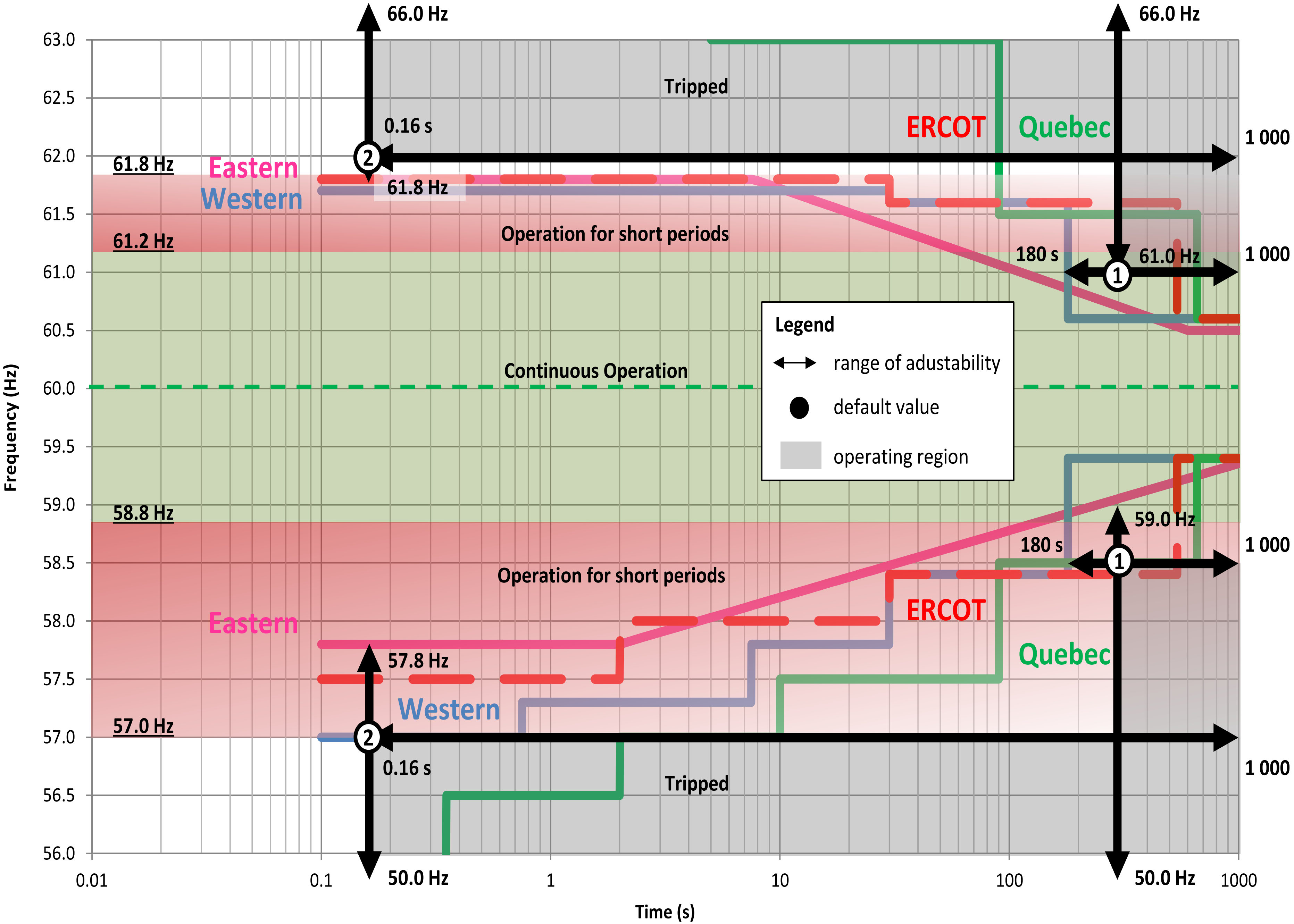
V, f Ride Through

- **Fundamentally, ride through is needed to avoid cascade failure of the utility grid during severe under frequency events, and to a lesser degree, severe under voltage events.**
- **Limit loss of generation to "an acceptable level"**
  - During severe under frequency events DER should remain online until local load shedding schemes have activated.
  - Local Load shedding schemes will shed load AND generation simultaneously thereby minimizing the net loss of generation during an event.
  - If DER is lost ahead of load, grid instability may quickly worsen and possible lead to cascade failure.


Category III
(based on CA Rule 21 and Hawaii)
may ride-through
or may trip
0.16 s
12 s
1.20 p.u.
shall trip
Momentary Cessation
1 s
13 s
1.10 p.u.
Continuous Operation
50 s
0.88 p.u.
21 s
20 s
Mandatory Operation
10 s
may
ride-through
or may trip
0.50 p.u.
2 s
21 s
Momentary Cessation
may ride-through
or may trip
0.00 p.u.
0.00 p.u.
shall trip
Legend
range of adustability
default value
shall trip zones
may ride-through or
may trip zones
shall ride-through zones
and operating regions
describing performance
Voltage (p.u.)
Time (s)
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
0.01
0.1
1
10
100


66.0 Hz
66.0 Hz
63.0
62.5
62.0
61.5
61.0
60.5
60.0
59.5
59.0
58.5
58.0
57.5
57.0
56.5
56.0
Tripped
0.16 s
ERCOT
Quebec
1 000 s
61.8 Hz
Eastern
Western
61.8 Hz
61.2 Hz
Operation for short periods
180 s
61.0 Hz
1 000 s
Legend
range of adustability
default value
operating region
Continuous Operation
Frequency (Hz)
58.8 Hz
59.0 Hz
180 s
1 000 s
Operation for short periods
Eastern
ERCOT
Quebec
57.8 Hz
Western
57.0 Hz
0.16 s
1 000 s
Tripped
0.01
0.1
50.0 Hz
1
10
100
50.0 Hz
1000
Time (s)

Reactive Power Control Functions

- **Primarily for Voltage Regulation on Feeders**
  - Watt priority – produces Var only if doing so does not reduce active power output
  - Var priority – requires over sizing DER or reductions in active power output
- **Fixed Power Factor**
  - Programmable PF (+/- 0.85)
  - Slightly inductive PF offsets voltage rise due to active power injections ($V = I^2 * R$)
- **Volt/Var**
  - Varies Var production in response to voltage
  - Includes dead bands and gradients
  - May lead to circulating Var / voltage stability issues.
- **Commanded Var**

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Active Power Control Functions

- **Maximum Power Level**
  - Fixed, based on time of day, in response to external command
  - Needed to balance load to generation, limit feeder currents
- **Frequency/Watt**
  - Reduces power based in response to rising frequency.
  - Adds frequency stability during over frequency events
  - Secondary control method in system wide restarts (frequency events)
  - Optional in CA, R21, Phase 1, Mandatory in HI, R14H
- **Volt/Watt**
  - Reductions in power in response to rising voltage
  - Relatively ineffective compared to reactive power control
  - Optional in CA, R21 Phase 1

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Return to Service / Ramp Rate Control

- **Return to Service**
  - Criteria and behavior at startup, following a ride through event, or following a trip.
  - Necessary for stability following grid events
- **Startup / Restart Ramp Rate**
  - Criteria – within normal V, f parameters
  - Intentional delay – 15 seconds (0-300 sec)
  - Ramp Rate – 2%/sec (0-100%/sec)
- **Normal Ramp Rate**
  - Criteria – V,f within any operating region
  - Intentional delay – 0 seconds (0-300 sec)
  - Ramp Rate – 100%/sec (0-100% /sec)
    - Ramp Rate applies during normal operation

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California Rule 21 / SIWG Update

Why was the CA Rule 21 / SWIG Formed ?

- **California IOU's were concerned over problems associated with rapid adoption of PV**
  - Wanted to avoid German experience, i.e. high cost retrofits
  - Wanted to implement advanced inverter functions immediately
  - IEEE 1547 had stagnated and IOU's were unwilling to wait any longer
- **Did it work ?**
  - ✓ Repeat of German experience is highly unlikely
    - Standardized functions and communications protocols exist
    - Inverters with advanced functionality and remote programmability are available today
  - ✓ IEEE 1547 is now undergoing full revision to accommodate advanced functionality
  - ✓ UL 1741 Supplement A will go to ballot within a few months
  - ✓ New requirements and tariffs are now in place at CA IOU's

CA Rule 21 - Status

- **The CPUC issued a final ruling on Phase 1 requirements on 18 December, 2014.**
  - The three IOU's filed tariffs with the PUC in January 2015
  - Tariffs are approved and in place
- **Revised Rule 21 Phase 1 is now in effect**
  - Permissive upon publication of Supplement A in UL 1741.
  - Becoming mandatory upon the latter of: 31 Dec 2015 or; 12 months after the publication of Supplement A in UL 1741
- **Phase 2 discussions on communications are underway**
  - Ability to update and verify settings of DER remotely
  - Initially envisioned as periodic set it and forget it (autonomous operation)
  - Near real time control envisioned for larger systems
  - For comment draft of interconnection handbook under review

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CA Rule 21 – Status (cont)

- **Phase 2 has reached consensus on data Models and Protocols**
  - IEC 61850 data model
  - SEP 2, IEEE 2030.5 protocol
  - Demarcation points still under discussion
  - Utility interconnection handbooks under development
- **Still debating which entities/devices communicate with each other**
  - Direct utility communications of DER units seems unlikely except for very large DER units
  - Direct utility communications to facilities level for large plants
  - Indirect communication to distributed DER through an abstraction layer seems like best model
    - Utilities, ISO's, Muni's, Co-ops
    - Manufacturers, System integrators, third party aggregators

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CA Rule 21 – Phase 3

- **Phase 3 was originally a parking lot for "tough" issues.**
  - Revenue impacting functions
    - F/W, V/W
    - Power limiting / curtailment
  - Dynamic reactive power
    - FIDVR response
- **The kitchen sink…**
  - 30 functions deemed high priority
  - 21 functions deemed M/L or NA

SIWG Functions (Services) Evaluated on Distribution Resource Planning (DRP) Values for Smart DER Functions - assume appropriate compensation to provide these services How Addressed in Rule 21? (1) Mandated with details in Rule 21 (2) Mandated in Rule 21, details referenced to Phase 3 doc (3) Optional but IF implemented, THEN compliant with Phase 3 document DER = Generation, Storage, Controllable Load ESS = Energy Storage Systems PCC = Facility or anywhere between DER and PCC meter			California IOUs			
			(1) Mandated capability in Rule 21?	(2) Mandated capability, details in a Phase 3	(3) Optional capability, but if impl, then com	IOU Comments
Utility Actions	Static	Access: DER and/or PCC nameplate data	x	x		Not part of normal communications, part of registration communications
		Access: DER/PCC capabilities and supported modes	x	x		Not part of normal communications, part of registration communications
	Monitoring	Monitor: DER and/or PCC status & measurements	x	x		Yes at the PCC or a virtual grouping ID for an aggregator. May be exempted for small systems less than 11kw
		Monitor: DER and/or PCC roles & operating states	x	x		Roles are not important, we do want a confirmation of operating states to ensure compliance with utility commands and/or indicate missed communications.
		Monitor: Permitted/available DER/PCC modes				Not important for operations because we are simply mandating functions that we expect to be present on demand - we know this by definiton of rule 21
	Controlling	Control: Start/stop DER	x	x		base functionality - e.g., useful during maintenance and/or emergency situation.
		Control: Enable/disable modes of DER/PCC	x	x		Assume modes map directly to commands - e.g., turn on dynamic volt-var support
		Control: Set mode parameters and curves	x	x		Need to be able adapt settings over time - e.g., adjust dead band settings
DER or PCC Autono-mous Modes	DER Real Power	Mode: Limit maximum DER real power output	x	x		This is a static limit that would not change based on general system conditions / constraints
		Mode: Set real power output of DER or up to PCC	x	x		Basic control function for dynamic real output control
		Mode: Soft-Start Reconnection	x	x		ramp rates should be settable
	ESS Real Power	Mode: Limit maximum ESS charging rate (Rule 2?)				generalize 14 to be capabile of covering energy storage, however this is outside of Rule 21 - Rule 2, 3, 15, and 16 are the venues for this
		Mode: Set real power (dis)charging rate of ESS	x	x		generalize 14 to be capabile of covering energy storage,
		Mode: Load / generation following by DER / ESS				mode beyond the scope of rule 21
		Mode: Smoothing of real power spikes / sags (ESS)				outside of scope beyond Rule 21, covered in ther areas as before.
		Mode: Set ramp rate for ESS charge & discharge				Needs to be combined with 15 for controlling ramp rates - only can deal with discharging in Rule 21.
	PF	Mode: Fixed power factor	x	x		basic function
	DER Freq. Support	Mode: High/low frequency ride-through or trip	x	x		basic function
		Mode: Frequency-watt (emergency)	x	x		Basic curve function
	ESS Freq. Support	Mode: AGC (CAISO sends Reg up and down to ESS)				beyond rule 21 scope
		Mode: Frequency smoothing (DER & ESS & EVs)				beyond rule 21 scope
		Mode: Frequency-watt (ESS)	x	x		Basic curve function
	Voltage Support	Mode: High/low voltage ride-through or trip	x	x		basic function
		Mode: Volt-var control	x	x		basic curve function - needs to be for both fast (voltages with 88% and 50%) and slow conditions
		Mode: Volt-watt control	x	x		Basic curve function
		Mode: Fast var support for voltage mitigations				remove this as it was combined this command with 28 above
		Mode: Dynamic reactive current support				remove this as it was combined this command with 28 above
Schedule d Actions	Scheduling	Sched: Schedule real power of ESS	x	x		yes, we want schedules/events in the future for all commands - e.g., prepare for intermitant/cloudy day. This should be generalized to support the total command set that is in scope for rule 21.
		Sched: Schedule real power of DER/PCC				combine with 32 above
		Sched: Schedule modes of DER/PCC				combine with 32 above, scheduling is relevant for all commands
		Sched: Receive FDEMS/Agg schedules of DER/PCC				beyond rule 21 scope at this time. Future visibilityof schedules for ISO and facilty resources connected to the distribution systems is useful.
Additional Phase 3 Functions	Functions rated M, L, or NA by IOUs	Monitor emergency alarms and events				defined by the functions above.
		Watt-Power Factor: Power factor shifts based on watt output				
		Imitate capacitor bank triggers				
		Short circuit current limiting by DER				
		Provide black start capabilities				
		Provide "spinning" or operational reserve as bid into market				
		Reactive power support during non-generating times				
		Single phase power control on multi-phase units				
		Backup Power for facility or microgrid				
		Flow Reservation for ESS or EV charging/discharging				
		Facility or Aggr. provides forecasts of energy or ancillary services				
		Facility or Aggr. provides micro-locational weather forecasts				
		Registration: Initiate automated "discovery" of DER systems				
		Initiate periodic tests, maintenance, patches, and updates				
		DC Fault Test during startup				
		DER assesses feeder configuration and characteristics				
		DER transitions to operate within an islanded microgrid				
		Determine optimal DERs to provide low cost energy				
		Determine optimal DERs to provide low emissions energy				
		Determine optimal DERs to provide renewable energy				
		DERs respond to real power pricing signals				
		DERs respond to ancillary services pricing signals				

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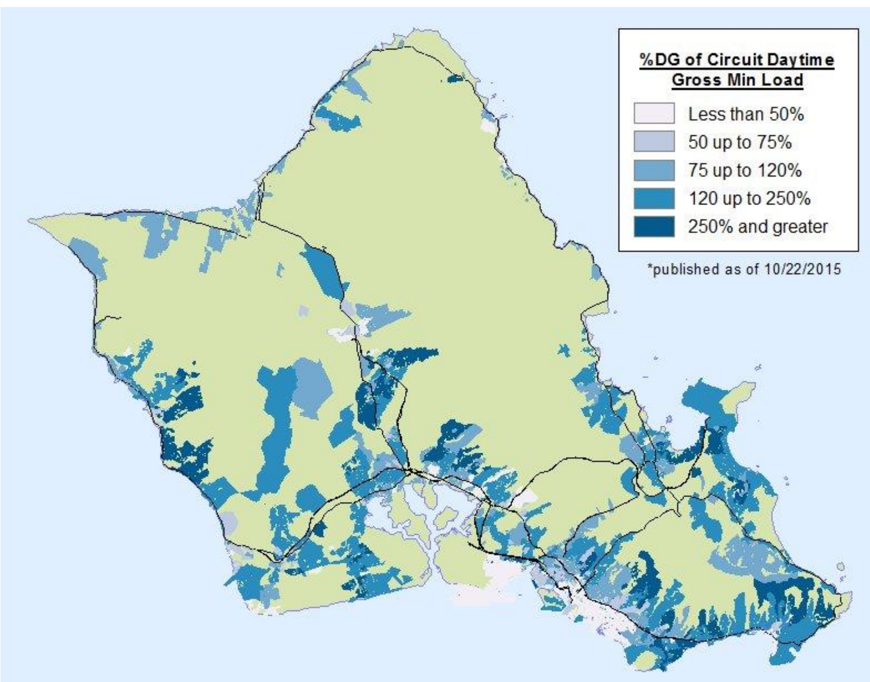
Hawai’i Experiance

The canary in the coal mine

Enphase Footprint in Hawaii

- **By HECO's estimate, Enphase inverters are used in 60% of all PV and 90% of residential PV installed in the State**
  - There is very high correlation between impacted feeders and Enphase system locations



Communications Example – Hawai'i Settings

- **On Oahu PV Generation is approximately 250 MW on a 1200 MW grid.**
  - In aggregate, PV is single largest generation unit (> 150 MW)
- **Hawaiian Electric (HECO) experienced two frequency events in last 24 months on Oahu**
- **Modeling suggested changes were needed to voltage and frequency ride through**
  - HECO worked with inverter industry to develop a two stage implementation plan
  - Interim settings based on existing UL 1741 certifications
  - Phase 2 settings required new UL 1741 certifications
- **At and of 2014 Enphase completed remote updates to ~ 800k inverters over two day period**
- **Update to final settings is underway now**

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HEI’s Full Ride Through Update

Full Ride Through Settings for O`ahu, Maui, and Hawai`i

January, 2015

Frequency Ride Through

Operating Region	Range (Hz)	Operating Mode	Duration (s)		Return To Service - Trip	
			Ride Through	Trip	Criteria (f, Hz)	Time Delay (s)
OFR2	f > 64.0	Cease to Energize	None	0.1667	60.1 ≥ f ≥ 59.9	300 - 600*
OFR1	64.0 ≥ f > 63.0	Ride Through	20	21	60.1 ≥ f ≥ 59.9	300 - 600*
NORH	63.0 ≥ f > 60.0	Normal Operation	Indefinite	Indefinite	-	-
NORL	60.0 ≥ f ≥ 57.0	Normal Operation	Indefinite	Indefinite	-	-
UFR1	57.0 > f ≥ 56.0	Ride Through	20	21	60.1 ≥ f ≥ 59.9	300 - 600*
UFR2	56.0 > f	Cease to Energize	None	0.1667	60.1 ≥ f ≥ 59.9	300 - 600*

Voltage Ride Through

Operating Region	Range (% of Nominal)	Operating Mode	Duration (s)		Return To Service - Trip	
			Ride Through	Trip	Criteria (% of Nominal)	Time Delay (s)
OVR2	V > 120	Cease to Energize	None	0.1667**	110 ≥ V ≥ 88	300 - 600*
OVR1	120 ≥ V > 110	Ride Through	0.92	1	110 ≥ V ≥ 88	300 - 600*
NORH	110 ≥ V > 100	Normal Operation	Indefinite	Indefinite	-	-
NORL	100 > V ≥ 88	Normal Operation	Indefinite	Indefinite	-	-
UVR1	88 > V ≥ 70	Ride Through	20	21	110 ≥ V ≥ 88	300 - 600*
UVR2	70 > V ≥ 50	Ride Through	10-20*	11-21*	110 ≥ V ≥ 88	300 - 600*
UVR3	50 > V	Permissive Operation	None	0.5	110 ≥ V ≥ 88	300 - 600*

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From HEI's 23 Feb 2015 Update to HPUC

- Docket No. 2014-0192 - Instituting a Proceeding to Investigate
- Distributed Energy Resource Policies, Monthly Update on Plan to "Clear the Queue." Filed October 31. 2014
- " With respect to interim settings, the Companies are pleased to report that Enphase Energy successfully upgraded the operating behavior of approximately 154 MW of its smart microinverter capacity installed in Hawai'i to achieve interim ride-through settings. This preliminary estimate represents about 107 MW on O'ahu, 22 MW on Hawai'i Island, 25 MW on Maui, 0.1 MW on Moloka'i, and 0.2 MW on Lana'i. This unprecedented technological accomplishment is a result of ongoing collaboration between Enphase, Hawaiian Electric and other industry partners to find technical solutions for integrating high levels of PV in Hawai'i at a low cost to end-customers. Because Enphase's microinverters are software-defined, Enphase was able to make these updates remotely and quickly, saving tens of millions of dollars by avoiding the need to send personnel out in the field to update the settings manually."

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HPUC October D&O

- **Elimination of NEM tariff**
  - Grid supply tariff – avoided cost for surplus energy
  - Self supply tariff – no export of energy
- **Advanced inverter functionality mandatory on 1 January 2016**
  - Full ride through settings plus
    - Reactive power control – FPF @ 0.95
    - Ramp rate control, F/W, V/W
    - Mandatory requirement for remote upgrades to inverters
- **Return to service criteria and behavior**
  - HPUC asked for analysis of +/- 0/1 Hz criteria
  - Restart ramp rate control is necessary to maintain stability
- **Begin phase 2 discussions within 30 days**

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Summary

Lessons Learned

- **CA Rule 21 / HI Rule 14H Smart Inverter functions add significant tools to the grid management toolbox**
  - Value of functionality increases with ability to control / change behaviors

- **Hypothesis:**
  - Need to change settings / optimize DER fleet will likely increase in frequency with higher penetration levels
  - Level of utility control of DER will increase as with level of penetration
- **Interconnection agreements should be reviewed in light of new functionality and update capability**

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Interconnection Agreement Issues

- **Need explicit permission to update settings.**
  - Rule 14H gives HEI authority to compel customers to make changes but does not give HEI authority to make changes directly.
  - Also needs to allow HEI agents or subcontractors to make changes
- **Overcome contractual customer privacy limitations**
  - Add limited privacy release to interconnection agreements
  - Allow confirmation of system location information for operation purposed only.
  - Critical to confirm changes to settings on individual systems
  - May be overcome through agency / subcontractor agreements
- **Amend existing installed base agreements if possible**
  - Large installed base with older IA’s complicates remote updates/ programming

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What is Still Needed ?

- **Develop cyber security standards for command and control of DER**
- **Create standardized model formats for advanced inverters**
  - Steady state, quasi-static time-series, PSCAD ??
  - Validate models with pilot studies
- **Conduct value analysis of advanced inverter functionality located at the grid edge to encourage customer participation**
  - Requires highly granular data below the substation
  - Include dynamic Var optimization along the feeder
    - Voltage regulation is by nature a distribution issue

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Thank you for your attention!

For questions contact John Berdner

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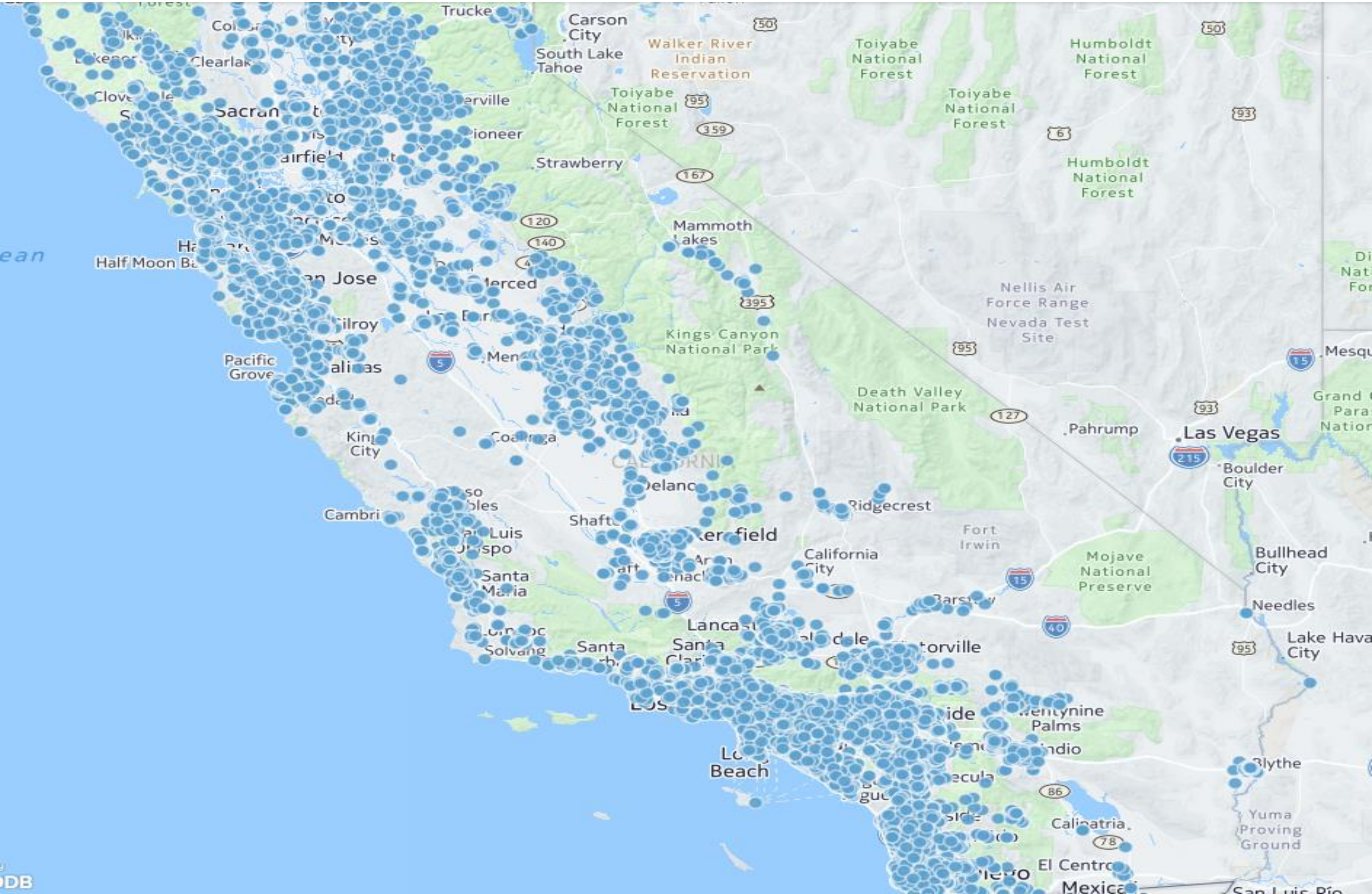
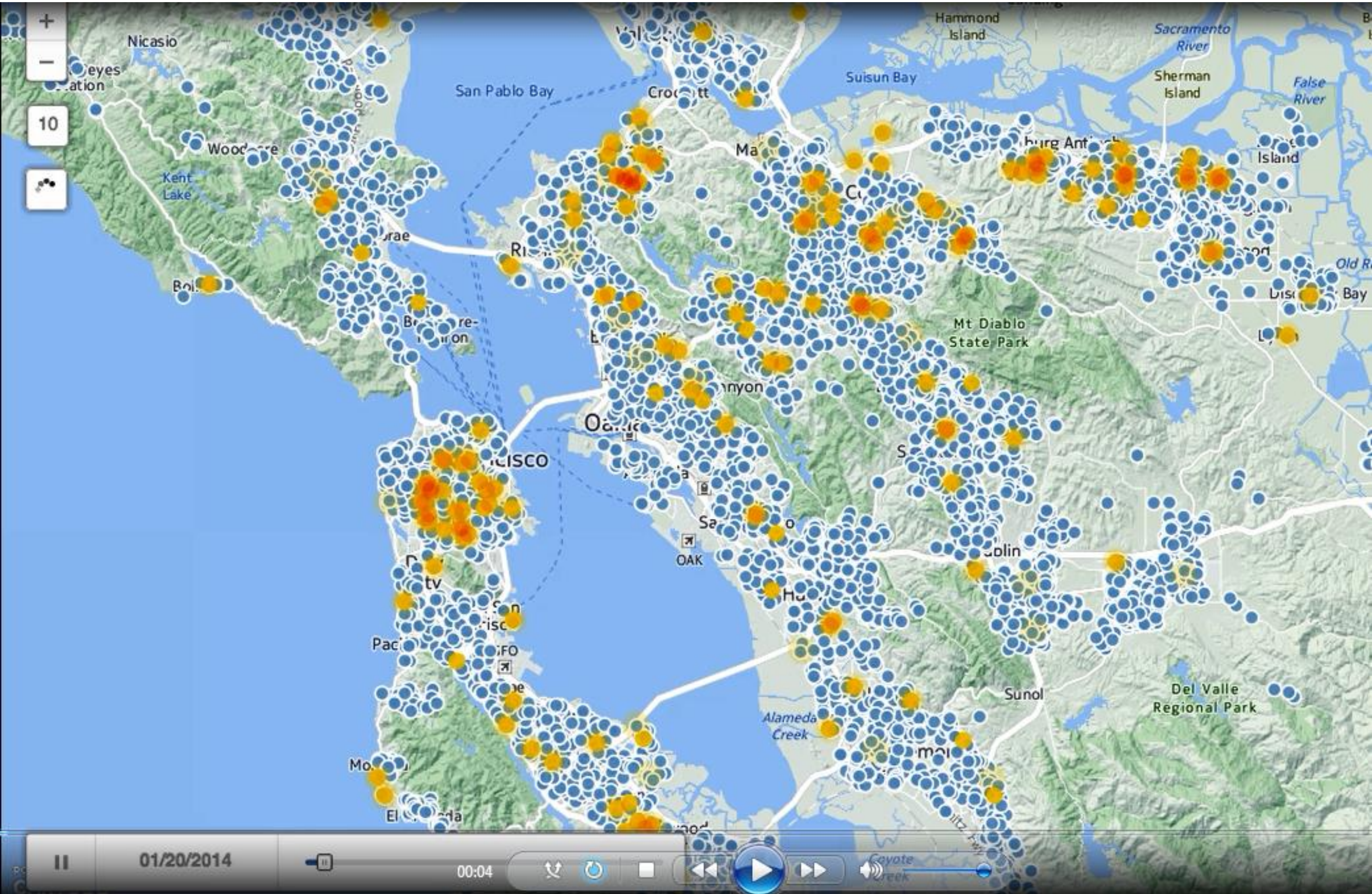
Supporting Slides

Enphase Footprint in California



Voltage Out of Range Visualization Movie



But, Is This Worth Doing ?

- **No standardized methodology exists to determine value of DER with advanced functionality.**
  - Traditional value analysis occurs only down to substation level
  - The majority of DER is located below the substation
  - Historic methodologies do not consider smart inverters located at the grid edge
  - Bottom up valuation methodologies are needed.
- **CPUC is engaging in DRP process to determine methodology for establishing the value of DER**
  - Significant value may exist below the substation especially when voltage regulation is considered
- **Integral Analytics / Enphase value study (preliminary)**
  - Value appears to increase as level of control granularity increases
- **Maine PUC solar valuation study: $0.337 / KWh**

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PRELIMINARY

Integral Analytics -Enphase Study: Benefits of dynamic KVAR control

- **Analysis at the grid edge, with small scale storage competing with kVar "injections", we find that the two are fairly comparable in terms of net savings and benefits (for avoided costs, grid purchases, and power factor changes)**
  - *Base Case: Optimally Located PV*
  - *Optimally Placed PV with Storage Added:*
    14% more savings
  - *Optimal PV with kVar/ Power Factor Control:*
    24% more savings
  - *Optimal PV, kVar and Storage:*
    26% more savings

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Maine PUC, Value of Distributed Solar Study

Figure ES- 2. CMP Distributed Value – 25 Year Levelized ($ per kWh)

25 Year Levelized		Gross Value A ($/kWh)	×	Load Match Factor B (%)	×	Loss Savings Factor (1+C) (%)	=	Distr. PV Value D ($/kWh)
Energy Supply	Avoided Energy Cost	$0.076				6.2%		$0.081
	Avoided Gen. Capacity Cost	$0.068		54.4%		9.3%		$0.040
	Avoided Res. Gen. Capacity Cost	$0.009		54.4%		9.3%		$0.005
	Avoided NG Pipeline Cost							
	Solar Integration Cost	($0.005)				6.2%		($0.005)
Transmission Delivery Service	Avoided Trans. Capacity Cost	$0.063		23.9%		9.3%		$0.016
Distribution Delivery Service	Avoided Dist. Capacity Cost							
	Voltage Regulation							
Environmental	Net Social Cost of Carbon	$0.020				6.2%		$0.021
	Net Social Cost of SO_2	$0.058				6.2%		$0.062
	Net Social Cost of NO_x	$0.012				6.2%		$0.013
Other	Market Price Response	$0.062				6.2%		$0.066
	Avoided Fuel Price Uncertainty	$0.035				6.2%		$0.037
								$0.337

Avoided Market Costs $0.138

Societal Benefits $0.199

From Maine PUC, *"Maine distributed solar valuation study"*, 1 March 2015, page 50

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